COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	
Preparation of the 2007 Integrated Energy Policy Report (2007 IEPR)	Docket No. 06-IEP-1J

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, MAY 15, 2007

9:00 A.M.

Reported by:
John Cota
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Jeffrey Byron, Associate Member

John Geesman, Associate Member

ADVISORS PRESENT

Melissa Jones

Tim Tutt

STAFF and CONTRACTORS PRESENT

Mike Jaske, PhD

Adam Pan

David Vidaver

Jim Woodward

ALSO PRESENT

Bob Strauss, California Public Utilities Commission

Tony Braun, California Municipal Utilities Association

Joe Lawlor, Pacific Gas & Electric Company (PG&E)

James Farrar, Turlock Irrigation District (via telephone)

Joe Heinzmann, FuelCell Energy (via telephone)

Nick Zettel, City of Redding

Brian Koch, Los Angeles Department of Water & Power, (LADWP), (via telephone)

Gary Lawson, Sacramento Municipal Utility District (SMUD)

Phil Pettingill, California Independent System Operator (CAISO)

Ernest Hahn, The Metropolitan Water District of Southern California

I N D E X

P R O C E E D I N G S

9:07 a.m.

PRESIDING MEMBER PFANNENSTIEL: I believe we are ready to begin. This is a staff workshop on resource adequacy policies and protocols for publicly owned utilities under the IEPR, the Integrated Energy Policy Report Committee.

I am Commissioner Jackie Pfannenstiel, I am the Presiding Commissioner on the Integrated Energy Policy Report Committee. To my left is Commissioner Jeff Byron, to my right is Commissioner John Geesman and to his right is Melissa Jones, his staff advisor.

And with that we can begin.

MR. WOODWARD: Thank you, Commissioner Pfannenstiel. I'm Jim Woodward with the Electricity Analysis Office of the California Energy Commission.

Welcome all of you here today. We have about 30 people here in the room and I understand a large listening audience on the web perhaps.

I need to make one important announcement for those who wish to call in. We regret that the number posted for the call-in is incorrect. The correct number is 800-857-6618. There's one digit off. The correct number is 800-857-6618. And we'll repeat that I hope several times this morning during the workshop.

One other housekeeping arrangement just for those here in the room. The closest restrooms are located out the doors across the hall, there's a snack bar on the second floor under the white awning. And if there is an emergency and we need to evacuate the room please follow employees to the appropriate exits. We'll reconvene at Roosevelt Park diagonally across the street from this building. Walk calmly and quickly following employees with whom you're meeting to safely exit.

And now on to the program. First an introduction about the topic today. This is a staff workshop on resource adequacy policies and protocols for publicly owned load-serving entities.

In 2005 Assembly Bill 380 Was passed and signed into law, adding Sections 380 and 9620 to the Public Utilities Code. These sections gave the Energy Commission a new responsibility to report every two years, as part of the IEPR, on how local publicly owned electric utilities are doing to plan for and procure resources to meet the needs of their end-use customers.

The intent of AB 380 was to ensure each load-serving entity engages in prudent planning to serve its end-use loads. The PUC was given jurisdiction to oversee procurement by electrical corporations, electric service providers and community choice aggregators. These are load-serving entities, LSEs for short, for whom the PUC already has some regulatory jurisdiction in other contexts.

Oddly enough, AB 380 said the term load-serving entity specifically does not include any local publicly owned electric utility, as defined in Section 9604 of the Public Utilities Code, and the term LSE does not include the State Water Project in AB 380. But the definition in AB 380 is at variance with common usage and today in this workshop we will often refer to local publicly owned electric utilities as LSEs.

And we are using the term publicly owned load serving entities today because we are pleased to report on the progress of many other types of LSE beyond those that would fit the narrow definition of being an electric utility.

This is a working definition that includes, for example, Cerritos as the state's one and only Community Aggregator. And it includes Shelter Cove as the state's one and only Resort Improvement District. And it includes four public Joint Powers Authorities, JPAs, that purchase supplies and serve loads that are connected to the distribution system of PG&E.

And our working definition of publicly owned LSEs includes four rural electric cooperatives, which are publicly owned and locally managed nonprofit corporations, all of them quite small. And we are quite pleased to report today information, in a summary way, that was voluntarily provided to us by the State Water Project and by the Western Area Power Administration regarding their plans and commitments to serve their forecast loads.

Before we into the substance of those resource plans and commitments it is necessary and appropriate to acknowledge the extent and depth of those organizations who have voluntarily contributed to this project. For most of these publicly owned LSEs there was no regulatory obligation to provide us information that we requested. Our proposed regulations for ongoing implementation of AB 380 are just now before the Office of Administrative Law. Our proposed changes to Section 1346 have benefited from the active participation by CMUA and several POUs.

Nonetheless, before that rulemaking is completed we wanted to engage publicly owned LSEs across the state to better understand what commitments exist on the local level, what's been accomplished recently, and what changes in the near future are anticipated. All along it has been our intent to report on these efforts for the first time as part of the 2007 Integrated Energy Policy Report. And to that end the Commission on January 3 instructions to the mid-size and large publicly owned utilities to report on their resource adequacy protocols. And the small publicly owned LSEs were requested to provide voluntarily this information if they had it, and most do.

Most of the filings we received were prepared with the encouragement of the California Municipal Utilities Association, CMUA, as approved and directed by its membership. The responses have all been fascinating, are remarkably complete and diverse. I also wish to personally thank all the resource planners who spoke with us, gave us email replies and shared with us some of the regulatory, economic and environmental contexts in which they do resource planning.

Today's workshop will highlight a few of those narrative elements. But first I'd like to bring up Dr. Michael Jaske who will set the state with questions we hope to address today and briefly describe the evolving context in California and the WECC that may establish new Resource Adequacy conventions. After Mike, Adam Pan will present a quantitative assessment for the mid-size and large POUs, their resource plans that look ahead ten years. To the extent there is time we'd like to encourage questions and comments at the end of each presentation.

Subsequent to this workshop we will prepare a technical and descriptive report that summarizes the progress made by each publicly owned LSE as expected by AB 380. That preliminary report will be presented at a second workshop set for July 2nd.

Once again I'll announce that the phone number for call-ins should be 800-857-6618. We have an operator standing by and his name is David Vidaver. And now Mike Jaske.

DR. JASKE: Thank you, Jim. Commissioners, participants in the workshop, my name is Mike Jaske of the Energy Commission staff. And I'd just like to make a few remarks setting the stage for how we think about Resource Adequacy from the publicly owned LSE perspective.

How we do that thinking, of course is very heavily colored by what's going on or other kinds of entities under the jurisdiction of the PUC and its Resource Adequacy program. Which was underway before AB 380 sort of removed any doubt about the PUC's authority to establish such a program and perhaps clarified some of the objectives of that program.

We have in addition the tariff requirements and sort of operational activities of the ISO within which most of the POUs, by number at least, find themselves. And the revolving requirements of the ISO, starting off with the IRRP tariff requirements but during '08 morphing into a revised set of requirements under the overall MRTU program.

We have the unique aspect that the POU

portion of AB 380 refers directly to any resource adequacy guidelines or requirements established by the Western Electricity Coordinating Council, or WECC for short. And WECC has been underway for about two years trying to develop its own resource adequacy program.

At this point in time at least WECC has no intention of that program leading to any kind of mandatory forward commitment obligations. It is entirely an assessment protocol that would provide information back out to the industry about the state of readiness of various portions of the WECC interconnection or perhaps even down to individual control areas, that is not yet clear, relative to some sort of benchmark.

And how that kind of formulation of a WECC program interacts with AB 380 is frankly a little confusing. There is such a terse reference in the language of the statute that one would perhaps need to guard against an assessment guideline on WECC's part somehow or other morphing itself into a procurement obligation on the part of POUs.

We have been at this for some time now, particularly with respect to how POUs should deal with Resource Adequacy. Present in the room today is Tony Braun with CMUA and he and I, Jim and some other folks authored a paper all the way back in the 2003 IEPR cycle about Resource Adequacy and how it is we should think about that kind of framework, that kind of guidance to procurement activities, to planning activities. It didn't lead directly to any kind of requirements but it helped bring us all into closer communication and a better understanding of what the various issues are.

And there are many of those issues. Jim indicated that there are a series of questions that are attached to the workshop notice. Those are ones that we posed in anticipation of this hoping, hoping that people who participate today will have some perspectives to offer. The agenda sort of organizes people in various ways. I hope as we work ourselves through that agenda that we can get some answers, or at least perspectives on those questions.

Let me just raise three or four specific things to sort of set the stage for the rest of the morning's discussion. First is, does one size fit all? Should every POU load serving entity be required to satisfy the same requirement? Is it practical for POUs that range all the way down to single digit megawatts to have the same requirements as POUs that have peak loads in the range of 1,000 megawatts?

Obviously there is the intellectual and overhead burden of complying with this kind of program. Even the informational reporting requirements that raise questions about how realistic it is to have precisely the same requirements on all LSEs.

Secondly, given the nature of publicly owned LSEs, most of which serve customers in a specific, confined geographic service area, which is effectively an island within a larger entity's transmission system, what are the opportunities for such a POU to acquire resources to satisfy Resource Adequacy when they don't really have the full range of choices that might be available to a larger entity?

Just to take a case in point, PG&E in its transmission planning manifestation versus PG&E in its load serving entity manifestation have certain opportunities to trade off generation versus transmission as options to deal with

Resource Adequacy requirements, particularly local capacity requirements.

A small POU embedded within the transmission system simply doesn't have the same set of options and choices available to it. So that creates a dilemma, both from the procurement perspective, from the creation of obligations that lead to procurement. But even from the planning perspective. That POU cannot in and of itself do the kind of tradeoff between transmission and generation. It simply doesn't have the information available to it. So kind of cooperative arrangement, at a minimum, seemed necessary so as to be able to pursue that full set of choices.

Dealing with POUs within the ISO. The FERC orders that have been issued last fall on MRTU and just a few weeks ago on issues on rehearing make it very clear that each of the POUs through their local regulatory authority almost all the time but not exclusively, almost all the time their board of directors have the opportunity to establish the parameters of a resource adequacy program. They have the right to determine what is the right planning reserve margin. How to set the rules for counting capacity.

That potentially leads to diversity in how those entities choose to do this and that diversity may create issues for the ISO. They may have different ideas about what's appropriate. But the way FERC is establishing the ISO tariff that right exists for each POU through their LRA.

And that may in fact be an interpretation of AB 380 itself. That may create a greater burden for the Energy Commission in sort of overseeing this, reporting to the Legislature about the diversity of choices that POUs are making about these matters and whether in our judgement they're making the right choice. So that's a perspective on how it is we communicate to the Legislature that this particular 2007 IEPR will have to deal with and presumably subsequent ones as well.

And then finally let me raise the particular issues associated with POUs to operate their own control areas where there are other utilities as part of that control area. SMUD and LADWP are, of course, large proportions of their respective control areas. They do have smaller POUs that are part of that control area.

What kind of responsibilities and obligations do control area operators have in sort of thinking ahead, planning for Resource Adequacy? AB 380 seems to be silent on this whole notion of the control area and any responsibilities it might have separate and apart from simply being a POU.

So those are the few issues that I think we're going to have to eventually deal with and I wanted to highlight those particular ones so when we have our discussion this morning those are fresh in people's minds.

I'm finished. If there are any questions from Commissioners or particular clarifying questions anyone from the audience wants to make, feel free.

No? Okay. Jim.

MR. WOODWARD: Thank you, Mike. And we will take comments and questions if we can after the end of each presentation. That covers our introductions.

Again, for callers the number to call in is 800-857-6618.

And now it is my pleasure to introduce our next speaker. A colleague of mine here in the Electricity Analysis Office of the California

Energy Commission, Adam Pan.

MR. PAN: Thank you, Jim. My name is Adam Pan of the Electricity Analysis Office. I am going to go through a quick look at the resource plans filed by the more traditional sense municipal utilities serving loads that's more than 200 megawatts. These municipal utilities add up to more than 90 percent of all the public utilities' load in California.

I am going to go in to look at the capacity information in the Form S-1. The energy data will be looked at in the report before the next workshop.

Of the utilities that filed ten-year resource plans the Commission granted the confidential treatment to Imperial Irrigation District's information. Imperial Irrigation District's information will be included in the aggregate of these utilities but it will not be shown individually.

These are the utilities with ten-year resource plan data that we're going to look at next. The group of utilities on the first column have the summer peak in August and the second column, their peak is in July.

Here is an aggregate of these utilities of non-coincident peak and their resources. As you can see the pink line on top is the demand plus reserve plus the sales obligations of these utilities and the blue line below it is the net peak demand. This is the forecast of the peak with adjustments for demand side programs and some other small programs.

The stacked bars are the resources available to meet the demand. As you can see the first section, the yellow bars are the utility controlled power plants. It almost meets the demand. The contracts are the light blue, some sort of blue. It's a significant portion but it's much smaller. It's about 3,000 megawatts in 2007. These two together almost meet the demand of the utilities plus reserve.

And on top of that there's some short term contracts and maybe some generic resources in 2007. The generic resources started to grow after that to be a significant portion in 2016. And the contracts will shrink probably based on the expiration of existing contracts.

Again, the top darker blue is the short term contracts. They are probably utility-anticipated short term contracts that utility plan to meet their demand, not with some longer term contracts or power plants but rather they're going to rely on the markets for short term contracts.

Here is a look at 2007. Of the contact types of that 3,000 megawatt contracts there's about a quarter that can be identified and linked to specific power plant units. About two-thirds ware with companies with power plants. These contracts are not linked to specific power plants but are probably backed by a portfolio of power plants. Examples are the Western Area Power Administration, the BPA and Calpine. These are types of counter-parties with resources to back up the contracts.

The ten percent are other types of contracts where we cannot identify either the portfolios or the specific units. They are probably in the more, like the liquidated damage kind of contracts.

Here is a look at all the power plants and contracts together and their resource types. It's somewhat of a guess since no precise information is available on each individual contract. But the thing is that BPA has hydro and

Calpine has mostly natural gas.

You can see about half is natural gas and a quarter is large hydro, a significant portion of coal. A little bit of nuclear and the renewables together add up to maybe five percent of the capacities. It probably will be more meaningful to look at resource types when we analyze the energy information provided to us in the resource plans.

What follows is a look at the ten year resource plans of the individual utilities. Again, IID is not included here. We are just following the alphabetical order of the entities here. The first one is Anaheim. We start out with about 600 megawatts of demand and it grows very slowly. Currently the power plants owned by Anaheim is not sufficient to meet the demands of their contracts. The DDR means dispatchable demand response and no interruption programs.

With short term contracts and other bilateral contracts and demand side response Anaheim is able it meet its demand. And Anaheim has plans to add power plants in their system to meet more of its demand and the contracts will diminish in size. There's generic resources in the later years. I think they are probably renewable contracts that needed to meet its RPS obligations.

Next is Burbank. Again load is pretty flat with very little growth. The higher demand in the first year included some sales obligations. Without that it will be more of a flat line. Burbank's old power plant by itself is adequate to meet all its demand but nevertheless they have contracts and a little bit of demand response to add on top of that. It looks like Burbank will rely on short term contracts as a, probably as a cost-saving strategy to balance out their power plant.

Next is Glendale. It basically provided a straight-line, flat forecast of its demand and there is no change in its power plants in the ten years time frame. And the contracts that it has right now will expire somewhat but the contracts are more than adequate to meet its needs. So obviously Glendale doesn't anticipate adding any resources.

Here is LA Department of Water and Power. This is our biggest municipal utility in the state. The net demand, the net peak is about

6,000 megawatts. The demand plus reserve is a little bit over 7,000. And you can see LA's plan is to meet its demand almost entirely with its own resources with its own power plants. There's a small sliver of demand response and a tiny bit of contracts on top of that. The demand is very flat and so the resource looks not very interesting but it looks very stable.

Modesto Irrigation District, looks very different. You can see its demand is growing at a steady rate. It doesn't look flat like the other utilities before this. The demand grows from 700 for the net and about 800 for the demand plus reserve. Those two close to 1,000 in 2016.

Right now Modesto's own power plants is about maybe half of its resources and the other half is the contracts. There is a little bit of demand side response that doesn't look like it changes over the period. Modesto is looking to use generic resources to fill its needs and short term contracts. So these are relatively unknown choices that Modesto will eventually show at some point.

Okay, I'll go a little bit more quickly through this. Pasadena, it's almost like Burbank, very flat, very uninteresting, very stable.

Redding, at the top of the Central Valley, it is also is growing fairly good. And there's a little bit of it own power plants and a section on contracts that is very stable. I think they are mostly Western Area Power Administration contracts. Redding will need generic resources in the future to meet its needs.

Riverside has a growth that's similar to Central Valley utilities. Its power plants covers the majority of its needs and current contracts and future contracts will be needed to meet its growth.

Roseville is growing very good and for 2007 its power plants and contracts are adequate to meet its needs. It hasn't shown what type of resources it will procure for the future years so it left a blank in its resource plan. We guess maybe some type of generics and short term contracts.

SMUD, it also grows at a steady rate. The future resource needs will be met mostly by the generic resources.

Silicon Valley Power is a little bit like Roseville. It doesn't plan much growth in its power plant and it left open as to what type of resources it will use to meet the future needs.

Last is the Turlock Irrigation District. The first year it had some sales obligations and it grows like other Central Valley utilities. It has power plants and contracts and it will use short term contracts for the future growth looks like.

ASSOCIATE MEMBER GEESMAN: Why the change in the reserve margin for Turlock between 2007 and 2008?

MR. PAN: Go back to that, sorry. The net peak -- This top line is its demand plus reserves then plus sales obligations. So remove the sales obligations, it's reserve is still the same as the other years.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. PAN: Is there any questions?

MR. STRAUSS: I have a couple of just clarifying questions.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, yes, please come up.

MR. STRAUSS: Bob Strauss with the California Public Utilities Commission. Just a couple of clarifying questions to understand the data you presented.

Did each POU present its own reserve margin so that they varied from POU to POU?

MR. PAN: No, actually not. I think all except LA presented the reserve margin at 15 percent. LA provided a resource, a reserve margin based on its own. I think as a control area it's probably based on some sort of largest contingency or something. I do not know the rationale fully but LA used a fixed amount for its reserve. All the other utilities used 15 percent.

But a few of them made adjustments to that 15 percent reserve margin with something called reserve credits. I looked at an example to, it looks like sometimes a combustion turbine was counted as a reserve credit so those reserve credits reduce their reserve margin slightly. But they started with the 15 percent.

MR. STRAUSS: Thank you. On the contracts you used portfolios and you counted portfolios with suppliers with their counter-parties that had generation. Now did the contracts themselves say that the supplier's generation was supporting the contract or could, for instance, Calpine being one counter-party, could they have gone out and bought on the market to supply that contract, or would the contract require them to use their portfolio?

MR. PAN: No, this is only a guess on our part. The information we requested in Form S-5 only asked whether the contract is unit-specific or not. It does not ask for, you know, the more detailed information in the contract so we do not, we haven't looked at the contract themselves to know.

MR. STRAUSS: So basically the 24 percent of units specific that are backed by generation, the other 75 percent of the contract terms don't say that they are backed by specific generation.

MR. PAN: Right.

MR. STRAUSS: Okay, thank you.

On the load forecasts that the POUs provided did the CEC do any analysis versus its own forecast methodology to see the reasonableness of those forecasts or if there is a discrepancy between the two modeling methods?

MR. PAN: I am not familiar with that. I'd probably have to get someone in our demand analysis office to answer your question.

MR. STRAUSS: So you didn't do an analysis on it?

MR. PAN: No.

MR. STRAUSS: Okay. Thank you very much.

MR. BRAUN: Tony Braun for CMUA. I probably can answer a couple of those questions that were asked. On the Turlock Irrigation District and the reduction in their margin it's because, we believe it's because when they started their own control area operation they did not have a reserve sharing arrangement with other entities so they had a higher margin because their operating reserves were driven off a single largest contingency that was higher than if you just go through the ISO control area or some other normal control area with a five to seven percent.

Similarly with LA. Their single largest for operating reserve requirements is higher and so therefore they have to do their planning reserve off that, which results in a higher, planning reserve margin.

On the contracts, and this is something that I think we're probably going to find out over time as we refine this analysis. You're lumping in a lot of different things. If you think of this as, well this is a contract, this is a contract that is a firm energy contract in the west or something like that.

I think what you're going to find if you start breaking down is that, as mentioned, WAPA is a contract. Well we know where WAPA's resources come from. They might not come from a particular unit but they come from a big portfolio of units that are readily identifiable.

A joint powers agreement could be the mode of ownership of a unit but it is actually a contract between the LSE and the unit owner, which is the joint power agreement. So there's a lot of refinement I think in the data as we start breaking this down and get this better as we do it repeatedly.

MR. PAN: Thank you.

MR. LAWLOR: All right, thank you. Joe Lawlor, Pacific Gas & Electric. I have been involved, and Tony has too, with Robert Strauss for a couple of years in the PUC's forum on Resource Adequacy. I think my questions are very much like Robert's, trying to understand exactly what I'm seeing here because of our work there.

Something we struggled over was kind of consistent counting rules. How would resource be counted from one LSE versus another to ensure that what we're seeing is consistent. Do you know or is there some kind of way of -- were the resources counted in a manner between the entities that were consistent and would you know if that is comparable to how the PUC's counting rules were developed?

MR. PAN: Jim will elaborate on that at some point but as far as I know these are, the utilities reported based on our form's instructions and I don't believe we have specified the formula, per se. So my guess is that everybody's understanding will be a little bit different so they are probably not entirely comparable.

MR. LAWLOR: And this looks like, I'm guessing this is an August peak look only.

MR. PAN: Yes. As I said in the beginning, some utilities are peaking in August, some in July, and this is a look at the peak either in July or August, individually. And when we looked at the aggregate we added up the peak whether they are in July or August so this was not a coincidence.

MR. LAWLOR: Will there be further work to look at other seasons or beyond that peak view?

MR. PAN: Probably we can present some charts and tables to show the variation of the resources in general. It may not be for each individual utility, it may be to look at the group as a whole. This can be done. Haven't thought about it very much.

MR. LAWLOR: And something that we -- and I appreciate Tony's comments earlier helping to clarify. Something that we spent some time on in the PUC forum, especially with the ISO, was LD contracts as an issue. You know, was a portfolio of resources something. Identified how to look at that. Or how to look at something that really doesn't have any backing. I think I heard Tony say maybe we'll do some further work to look at what this portfolio designation is. You want to correct that?

MR. BRAUN: I think there's two steps to this. One, when you look at -- to use specific examples is always easier for me. Modesto, Santa Clara and Redding have a contract with San Juan Unit 4. It's a contract. But they are a part of the joint power -- part of an authority that runs, helps administer the plant. So it looks, legally it's a contract, it looks like ownership rights. How we parse those out, how we categorize them or what color they are, probably something that needs refinement.

On the LD contract, we frankly think that the PUC made the wrong decision. But for some of our folks it is not an issue, practically. For some of our folks that is an issue what the PUC decided so we'll see how that goes forward.

MR. LAWLOR: Absolutely. Thanks for the clarification. Thanks, Tony. Do you know we'll we -- Did I understand correct that maybe this designation will be divided between those lines a little further?

MR. PAN: The contracts, as I told you we don't have a very good understanding of the different types so it may be a little bit difficult to divide and to say for sure what they are much more than what we show here.

MR. LAWLOR: Thanks again, I appreciate the work.

MR. VIDAVER: We have someone on the line from Turlock Irrigation District who would like to speak, James Farrar. Operator, would you put him on. Operator? Mr. Farrar?

MR. FARRAR: Yes.

MR. VIDAVER: Would you like to speak?

MR. FARRAR: Yes. I just wanted to clarify. I think actually the reason our reserves are higher in the beginning is as Mr. Pan indicated, we had a change in contracts in 2007 to 2008. I believe our requirement is 15 percent of our, of our load throughout the time period.

MR. PAN: Okay, we got that. So Turlock's reserve is always 15 percent. The first year higher, demand plus reserve, is because of the sales obligations in that year.

MR. VIDAVER: We have another person on the line who would like to speak. Joe Heinzmann of FuelCell Energy. Operator.

MR. HEINZMANN: Thank you very much. Yes, Joe Heinzmann, FuelCell Energy.

The question I had has to do with reserve, especially with the smaller districts where maybe they're made up of only one to, you know, maybe three power plants. That if one of those went down there would certainly be a larger chunk then the 15 percent reserve, I would think.

Has there been any visibility into that when you look at the power plants owned by the districts?

MR. PAN: I do not know how to answer this question. Maybe later on that --

MR. HEINZMANN: Does the question make sense, though? What I'm asking.

MR. PAN: Yes, yes. It's something that I am not familiar with, how it's dealt with. How much a single contingency is being dealt with a small system. It's just that I do not have the understanding to tell you.

MR. ZETTEL: Nick Zettel from Redding. I just want to make a real quick comment. I think Adam has done a great job here. This is what I have to do for my director and my city council, he's done it for 13 utilities. So this is a --

MR. PAN: Thank you.

MR. ZETTEL: It looks fairly simple but it's a lot of work.

But on the second page on the first bar chart the current resource outlook with all of the utilities combined. As a resource planner this is what I would expect to see. Mostly generation, a percentage of contracts and a small percentage of short term contracts. This is a good mix. And it covers the planning reserves without a lot of surplus.

So what this really, you know, what it tells me is the utilities have met their obligations. Not a lot of surplus, not a lot of hope that they could return their earned returns to pay down their debt on the market. In other words, it fits their risk profile very well.

And if you just want to flip to Redding's chart real quick. I think it always helps to give a little insight from the utility and the resource planner who actually made this chart and submitted Form S-1 to the office.

You can see our load is growing at a fairly good clip. And what is actually happening is a combination of native load growth and other expected industrial growth from a business park that we're constructing up in Redding. And we have had a lot of interest and it should be opening within the next year.

But you see the generic resources. On a resource planning basis it takes time to get resources. It takes time to build power plants, get transmission. It takes time to sign contracts. So you'll see that we have got this coming on in 2010, generic resources, which is a few years before we would need them for planning reserve purposes. We do that because you want the buffer. Because things go wrong, construction lead times take longer, or load happens faster than you thought it was going to happen.

I know in the PUC they have the one year-one month time frame. In our world you wait one year-one month you're behind because you can't put up a power plant in one year or one month. And really signing contracts takes quite a long time, as you're well aware of.

I thought it would be helpful to give some insight as to why a generic resource would come on maybe three years before you need it because these things, they're chunky and they come in segments. They don't just slide right in right when you need them.

But those are my comments. I'd like to once again let Adam know he did a really good job on the report.

PRESIDING MEMBER PFANNENSTIEL: Thank you. May I just ask a question on your slide?

MR. ZETTEL: Um-hmm.

PRESIDING MEMBER PFANNENSTIEL: The

increase in demand you said was a projected increase based on some business development that you have going on there so you're encouraging that growth, you're looking for that. But I don't see anything in the way of demand response or anything to help level the peak. Is there stuff in here that just doesn't show up --

MR. ZETTEL: Yes.

PRESIDING MEMBER PFANNENSTIEL: -- because they're non-dispatchable? Demand response or something like that.

MR. ZETTEL: This is, this is something that -- Redding incorporates our non-dispatchable peak reduction programs in our load forecast. And this has always been an issue of how do we show that or how do we not show it. When we report to the WECC our non-dispatchable programs are incorporated into the load forecast. Dispatchable is shown as a resource and it is actually shown as almost as a supply, a credit to supply. But right now we incorporate them in our load forecast.

PRESIDING MEMBER PFANNENSTIEL: But I don't see any dispatchable here either.

MR. ZETTEL: Redding doesn't have any dispatchable programs.

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. ZETTEL: We used to have an AC cycling program but it's pretty hot in Redding. Turning off people's air conditioners when it's 115 wasn't a very good program.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. ZETTEL: Thank you.

MR. PAN: Okay, that will be, that will be all from me.

MR. WOODWARD: Thank you, Adam. Thank you, Adam, good job. Appreciate the comments and questions.

My name is Jim Woodward with the Electricity Analysis Office. I'd like to present a survey of Resource Adequacy protocols and policies as they exist across the electrical geography of the state of California. Quite a bit of diversity we found and there's a lot of work in progress.

So where to begin? The word of the is adequacy. And I hope all of you are feeling adequate. For Resource Adequacy we are talking about what is suitable or what is sufficient. What does it take to be able to satisfy requirements to serve forecast load or real-time load? And when do you need to have it? What counts as enough and for whom? And who has to be satisfied?

It may help to review -- It may help to review what Resource Adequacy rules and policies are meant to accomplish. AB 380 set forth five objectives for the PUC to meet by working together with the ISO and those LSEs under its jurisdiction: Facilitate development of new generating capacity.

Second, retain existing generating capacity that is economic and needed. AB 380 actually lists both these objectives as number one, and perhaps they are two sides to the same coin; but different proceedings tend to address one objective well and the other objective not so well. So they are listed here separately for clarity.

Third, allocate costs of Resource Adequacy generating capacity equitably. Four, prevent cost shifting among customer classes. And five, minimize requirements and enforcement costs.

For the Energy Commission there are no parallel practical objectives for Resource

Adequacy, at least as defined in AB 380. Instead the mandate is squarely placed on each -- let me make this a slide show. Here we go. The mandate is squarely placed on each publicly owned electric utility to prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand for service to its customers, end quote.

AB 380 defines only one clear standard by which Resource Adequacy must be measured and that is, quote, to meet the most minimum planning reserve and reliability criteria approved by the Western Systems Coordinating Council or the Western Electricity Coordinating Council. As most of us know there are operating standards in place for control areas. Planning criteria that might apply to LSEs are just now being considered by committees of the WECC.

Professor James Bushnell has reminded us that RA rules ideally combine goals of reliability with the economic paradigms about investing in capacity. First and foremost the desire for resource adequacy standards is driven by a belief that electricity supply interruptions should be very rare or preferably non-assistant. A third goal of RA policies, as implemented by the CPUC and ISO tariff, again quoting Bushnell, is to provide a mechanism for ISO control over the commitment of generation resources necessary to meet local reliability needs.

To a very large extent it appears that publicly owned LSEs are doing their part to ensure forward contracting and procurement of utility-owned generation to serve their own loads. And in terms of facilitating new generating capacity expansion, they have been doing their share right through the restructuring of California's energy markets. Some POUs, such as Vernon, are planning for new capacity well beyond their own obligations. But this is an exception to the general norm that POUs seek adequate capacity and energy resources only to meet their own local obligations.

Mid-size and large POUs continue to engage in periodic integrated resource planning to serve native load. As vertically integrated utilities they have more certainty about their future bundled loads than do the IOUs. Procurement decisions have long lead times, sometimes well beyond the ten-year forecast horizon through 2016 in our data requests.

These procurement decisions look at least-cost options to add capacity or purchases for a variety of reasons: serving load growth, replacing less efficient older plants, boosting local reliability, meeting renewable energy goals and keeping rates low. And these have tradeoffs.

Glendale is one utility that is already resource adequate out many years for both capacity and energy. "However," as Glendale said in its filing, "the goal of Glendale's RPS is to procure additional quantities of renewable energy in the years ahead. Therefore a challenge Glendale Water & Power faces is to economically add renewable energy to its portfolio." End quote.

Before looking at other California LSEs I'd like to offer one perspective on RA from the Pacific Northwest. In May 2006 the Northwest Power and Conservation Council adopted an RA standard for its own power planning process and it recommended that utilities and public entities in the region also incorporate that standard into their planning efforts.

John Fazio, a senior power planner with the Council, said this in the April 23 issue of

Clearing Up. "There are sufficient resources within the region right now to assure the region the lights will stay on. But that's only part of the picture. The other part of the message is, there are lots of actions we ought to be taking right now, in spite of the fact the region has a surplus. We don't want to just be keeping the lights on; we want to be more fiscally responsible, and avoid situations like 2001 where we had these huge swings in prices." End quote.

In the Northwest RA Forum a steering committee is struggling now with how these regional RA standards might be expressed in terms appropriate for individual LSEs. The consensus thus far has been to provide non-binding guidance to LSEs and to rely on governing boards and state utility regulators to act prudently in the Northwest.

In one respect the publicly owned LSEs have not done as much, compared to LSEs under PUC jurisdiction, to make capacity available to the ISO. This is especially true for those LSEs that belong to the eight other control areas in the geographic state of California.

And this description totally includes

one POU that is not even connected to the grid. The Cit of Victorville is an island utility with a peak load of 3.6 megawatts in 2006. Since George Air Force Base was decommissioned in 2000 Victorville has been providing electricity to the Southern California Logistics Airport and another development area.

These two areas are served by 12 small generators, mostly diesel and some gas, and they are looking to add biodiesel fuel such as B20. On this very small, independent system Victorville must be self-sufficient with adequate power, even during unscheduled maintenance or generator outages. So Victorville uses the N+1 engineering standard. That means most of the time Victorville operates with a 100 percent reserve margin. There's Victorville.

Now I'd like to spend two minutes talking about little-known Needles on the west side of the Colorado River. The city of Needles has an annual peak load of up to 20 megawatts that could occur in July, August or late June. Last year's peak was 18.9 megawatts. The peak in non-summer months is seven to eight megawatts.

The city of Needles gets a six megawatt

package of allocations from the Parker-Davis Project, deliverable to the Mead substation in Nevada. Up there is Mead. And Mead is where, logically, Needles might take all its deliveries. But during the summer months Needles is restricted by Nevada Power on the number of megawatts it can bring in at Mead. So in June, July and August, Needles must bring in purchased power at the Eldorado delivery point.

Currently Needles is repackaging those Western allocations and is purchasing LD contracts from Pinnacle West or APS, typically for three, six or nine months at a time. Unfortunately for Needles, no one has been found willing to sign a long-term contract to deliver power for nine months of the year to Mead and then three months of the year at Eldorado. These things I've learned from talking to Dave Coke who does their market purchases.

The LD contracts are fully acceptable to Nevada Power as a demonstration of Resource Adequacy. Needles has a Coordination Agreement with Nevada Power to be in the Nevada Power control area. Nevada Power sells all the reserves, spin and non-spin, that are required of

Needles.

Now if Needles is short or under-scheduled in real time -- that's not where I want to go. How do I back up here? If Needles is short in real time Nevada Power will absorb and integrate that surplus energy and will pay Needles somewhere between $10 and $17 a megawatt hour.

So it is much worse. And if Needles is long -- I'm sorry, that's what Nevada Power pays if Needles is long. If Needles is short Nevada Power will make up the balance at a cost in April averaging $70 per megawatt hour. So it is much worse financially for Needles to be long than short. The ideal for Needles is to be just short.

The tariff is in place to protect Nevada Power from merchants that might otherwise dump power in that direction. But as a consequence Needles has no interest in and no need for a planning reserve margin that would lead to procuring 115 percent of forecast load.

So with Victorville and Needles we have the variations in day-ahead planning reserve margins bracketed from 100 percent above load at one extreme to slightly negative at the other extreme.

The scheduling coordinator for Needles is the Phoenix office of Western. But neither Western nor Nevada Power deals directly with the California ISO. So when Needles purchases power from a supplier to the west in California, Needles can end up paying three scheduling coordinators to move that power the last 40 miles.

To address this long-term reliability challenge, and in hopes of saving about $10 per megawatt hour, Needles is building a ten-mile transmission line, a 69 kV line, from Needles to Topock, a line that could be completed early next year. This line would give Needles a connection on the Parker-Davis 500 kV line. And after that Needles may shift from Nevada Power's Control Area to Western's Southwest Control Area, currently based in Arizona.

One other LSE serves -- let's see. One other LSE serves a tiny bit of load in Eastern California. Valley Electric Association, based in Pahrump, and nearly all its service area is in Nevada. Annual peak loads come in summer or winter, 115 megawatts in September, 124 megawatts last January.

According to Terry Stagg, their Power

Supply Manager, Valley Electric serves a few rural irrigators in California near Fish Lake and Tecopa and for them the peak load is always in summer, about 2.8 megawatts.

Valley Electric relies on a combination of Western, long-term contracts and market purchases. They are connected with Mead at -- connected with Western at Mead and tied into Nevada Power at Jackass Flat. Sometimes they get nine to ten megawatts of unscheduled loop flow through Jackass Flat. Western provides the supply, manages interconnection and provides the voltage support. It's firm energy to Valley. Nonetheless, Nevada Power charges Valley for what it thinks Valley's reserves ought to be, about five percent of load. Valley does not argue, as sometimes Valley calls on those reserves to meet its own loads.

Planning and coordination is fairly simply. Valley Electric tells Nevada Power a month ahead what loads are expected, then does the scheduling a day ahead.

One other rural electric co-op serves loads in multiple states. Surprise Valley Electrification up in Modoc County. It's quite rural with about two consumers per mile of line. Surprise Valley buys all its power from Bonneville Power Administration and feels BPA has been good for them. Surprise Valley is a 100 percent full requirements customer of BPA and is technically in the Bonneville Control area, something I learned just last week. Mistakenly I thought it was part of PacifiCorp's control area. And Bonneville Power is wheeled into Surprise Valley across PacifiCorp transmission, so their voltages are synchronized.

Sierra Pacific operates a control area in Nevada and California. Truckee Donner Public Utility district is a network customer of that control area. Annual peak loads measured at the district's meter are now 33 megawatts, winter peaking, not including transmission losses to get it there.

For this year at least all of Truckee Donner's supplies are provided by Constellation Power Source using Sierra Pacific as the transmission provider. The point of reception is Gonder, Utah, using Sierra Pacific's IPP transmission line. Truckee Donner has the option of providing its own reserves or purchasing operating reserves from the transmission provider, or purchasing them from a third party.

In the California ISO there are at least three publicly owned LSEs that are resource adequate for decades to come, yet they have no planning reserve margin whatsoever. Two of these entities don't even forecast or monitor their peak loads, nor need they. These two are the Calaveras Public Power Agency and the Tuolumne County Public Power Agency.

All the end-use customers are local public agencies with entitlements to federal power. Western provides supplies and serves as portfolio manager for all filings at the ISO. Neither Calaveras nor Tuolumne County have any distribution infrastructure. Their loads, which peak at only 33 megawatts together, are embedded in the utility distribution company loads of PG&E.

Trinity Public Utilities District gets all the electricity it needs from Western. By federal law Trinity PUD could take up to 25 percent of the energy generated within the county by the Central Valley Project, though it can take it only for consumption within the county.

When I talked to general manager Rick

Coleman on February 28, Trinity PUD was in day two of a power outage caused by a winter storm that had knocked out PG&E transmission. Oddly enough the energy from Trinity Dam, which is up there, is sent to the Sacramento Valley on Western's transmission to Cottonwood sub then comes back into Trinity County on PG&E transmission.

Transmission outages on PG&E's system are far and away the number one case of outages for Trinity PUD according to Mr. Coleman and these can last for days. To improve local reliability Trinity PUD is now constructing its own 5.3 mile, 60 kV transmission line under the auspices of Western so that 90 percent of Trinity load will be independent of PG&E transmission.

Trinity PUD is a reluctant member of the ISO control area. As a result of lengthy settlement negotiations the ISO signed a Small UDC operating agreement that allows Trinity PUD not to suffer an assigned share of rotating outages if and when ISO system resources are inadequate. When that T-line project from Trinity Dam to Weaverville is completed Trinity PUD may have the option of switching some 90 percent of its load to the SMUD/Western control area.

To the east of Trinity County, Lassen Municipal Utilities District is a full load customer of Western and had a peak load in 2006 of 25 megawatts. All of Lassen's supply comes from PG&E transmission at Westwood. And at least for accounting purposes, Lassen wheels a few megawatts of geothermal and biomass energy back to PG&E across that same interconnection.

Two other Joint Powers Agencies have been created in recent years. The Water & Power Resources Pooling Authority is comprised of 15 public water purveyors that organized in 2004. This LSE had a peak load last year of 120 megawatts and serves as its own scheduling coordinator. The water agency and water district members of this JPA get half their energy from a combination of Western and other contract purchases. The other half is still part of PG&E's bundled customer load.

The Eastside Power Authority had a peak load of just 13 megawatts last year. Eastside has three irrigation districts and three water districts on the east side of the San Joaquin Valley. Five of those six have rights to public power from Western so Eastside had to purchase power and reserves from the market for RA compliance. Both these LSEs kindly provided us copies of their years-ahead Resource Adequacy filings that were due to the ISO last November 2. And again in this case Western is the scheduling coordinator for Eastside.

At least three other micro-size POUs are embedded in the distribution system of PG&E. Shelter Cove on the coast of southern Humboldt County buys all its power from Western, who serves as their SC. Peak load in this unique Resort Improvement District is usually in December, about 0.7 megawatts and growing.

California's newest and smallest publicly owned utility and LSE is located on the southwest edge of the city of Bakersfield. McAllister Ranch Irrigation District began service on February 5 this year. The 2,000 acre parcel is being developed by SunCal Companies for 6,000 residential units at build-out. And Sun-Cal has prospective developments in the Mojave Desert that may reach 30,000 acres, including new electric LSE's.

At first McAllister Ranch simply leaned on the system and paid the ISO for imbalance energy. Now McAllister Ranch uses Sempra Energy Solutions as its SC. Bob DeKorne emailed us to say peak load this year will be well under one megawatt, adding, quote: "Thanks for not putting us through the reporting process for the current year. Recognizing that the process is voluntary for now, we do want to cooperate with the CEC's efforts to get its arms around the resource adequacy issue."

The Greater Bay Area load pocket has two similarly small and new POUs that have vastly different portfolios and RA concerns. The City of Pittsburg now owns the distribution system on Vallejo's Mare Island. Doing business as Island Energy peak load was 4.5 megawatts last year. Western meets all their requirements so this LSE has no formal RA policies and no need for such.

The distribution system on Mare Island is massive and was built for industrial uses related to the naval shipyard. Actual energy deliveries nowadays are quite low. Losses in that distribution system amount to almost 20 percent, perhaps the highest in the state. It's believed nothing economic can be done to reduce those losses without substantial load growth. Now that the housing market in Mare Island has slowed this utility is struggling with finances.

Just to the south of Carquinez Straits, Hercules Municipal Utility had a peak load of 2.6 megawatts last year. Hercules has an RA policy in the works for city council approval and uses Sempra as SC at the ISO. Hercules procures all its supplies by purchase contracts, including month-ahead, day-ahead and long-term for multiple years. Hercules has been 100 percent green thus far by purchasing green tags.

Hercules watches its own loads closely and carefully and does its own forecasting. Hercules tracks outages on its distribution system and claims its service reliability in this regard is orders of magnitude better than the Bay Area's IOU.

Hercules does not have any exclusive distribution service area and competes head-to-head with PG&E for extending new wires to developing areas. Based on this competition Hercules has been doubling its housing load every year for the past three years. As an aside I'd simply like to note that when different types of LSEs compete for new retail customers it can generate an immense number of legal filings that clog any number of regulatory proceedings.

In the Central Valley the Port of Stockton had a non-coincident peak of 2.8 megawatts last year. Sempra again provides all their electricity supplies and requirements, including service as SC. The Port of Stockton considers itself fortunate to even have a wholesale supplier and scheduling coordinator for its minuscule load. The Port anticipates some load growth over the next few years and is looking to take 60 kV service from the grid someday by building its own substation there on Rough & Ready Island.

Moving up in size now, there are four mid-size publicly owned utilities, electric utilities in the California ISO control area: Silicon Valley Power, Anaheim, Pasadena and Riverside.

Silicon Valley Power has good statements on RA that were incorporated a year ago into their Integrated Energy Resource Policy, a wonderful idea. Silicon Valley begins with a commitment to whatever standards are established by NERC and WECC, followed by intentions to "meet or exceed the standard of care in the industry, Good Utility Practice," unquote. This good phrase appears in the RA policies of several other LSEs.

Silicon Valley has a metered subsystem agreement with the ISO, as do several other LSEs such as Anaheim, Vernon and the NCPA power pool. By virtue of this metered subsystem agreement SVP's generating resources are not subject to the ISO must-offer requirements. Silicon Valley provides annual RA filings to the ISO and uses NCPA as their scheduling coordinator. Silicon Valley, by adopted policy, uses a 15 percent planning reserve margin based on their non-coincident peak demand forecast, irrespective of the California ISO system coincident peak.

The Anaheim City Council was one of the first to formally adopt a program for Resource Adequacy, a program that addresses both energy and capacity forecasting and procurement. Anaheim prepares an Annual Resource Adequacy Plan that identifies resources, quote, "sufficient to initially meet the greater of 112 percent of Anaheim's forecast monthly peak loads for October through April and 100.8 percent of Anaheim's forecast monthly peak loads for May through

September. Overall the objective of the plan will be to achieve no less than a 12 percent reserve margin over monthly peak loads transitioning to a minimum 15 percent reserve margin by 2010.

Like the majority of LSEs that define this term Anaheim says qualifying capacity of thermal generating facilities will be based on net dependable capacity as defined by GADS, which is the Generating Availability Data System of NERC. As a metered subsystem Anaheim will make available to the ISO, during a system emergency, all available capacity that is not required to serve Anaheim's loads.

Pasadena Water and Power provided Resource Adequacy Narratives that are a delight to read and the RA policies are integrated with their long-term resource planning. I'm quoting now: "Pasadena has historically maintained a 15 percent planning reserve margin. The system net peak demand includes distribution losses which average approximately five percent. Pasadena assumes transmission losses of three percent, thus the total busbar resource capacity requirement is effectively 18.5 percent of system load.

"Pasadena generally makes all on-site

generating resources in excess of meeting load available to the ISO for ancillary services, doing so by participating in the ancillary services market. By purchasing its operating reserves needs from the ISO Pasadena meets its operating reserve requirements separately from its resource adequacy obligations. Pasadena's local generating units fall under the FERC Must Offer Obligation regulations.

The majority of Pasadena's long-term energy resource portfolio consists of unit contingent imports. Due to the nature of Pasadena's distribution system, Pasadena has a longstanding policy to maintain at least 150 megawatts to 200 megawatts of generating capacity within Pasadena's service territory.

Pasadena currently has 197 megawatts of on-site generation, which represents 64 percent of Pasadena's historical all-time high peak of 316 megawatts in July 2006. For the future the IRP describes Pasadena's intent to repower our oldest and least efficient generating units, that 110 megawatts of the 197, by 2010.

The City of Riverside Public Utilities Department adopted a Resource Adequacy Program in

May 2006. I'll defer to Ron Barry of Riverside, who I hope will be calling in later to highlight Riverside's RA plans in a few minutes. The RA program established capacity counting conventions for resources that are dynamically scheduled or energy limited to renewable.

Riverside has adopted a 15 percent planning reserve margin "measured at the Cal-ISO take out point, Vista substation. The value at Vista includes distribution losses. An additional three percent is added to the forecast value to estimate transmission losses to Vista." During the heat storm last July Riverside served an all-time peak load of 587 megawatts.

While we are in Riverside County I'd like to point to a rural electric cooperative that is included in Edison's UDC loads. That would be Anza Electric Cooperative, Incorporated, which buys all its supplies from Arizona Power Cooperative. This co-op power provider has an all requirements transmission and delivery obligation to Anza Electric and serves as SC.

Anza has grandfathered transmission rights for ten megawatts on the Mead to Valley path and firm transmission rights, I believe, on the Edison system from Valley to Mountain Center switch station where Anza takes delivery of ten megawatts.

But Anza had an all-time peak load of 12.5 megawatts during the heat storm last July. So APCO is working with Southwest Transcro for the piece above ten megawatts, maybe trading one ICE someday soon. And for the piece into Anza above ten megawatts APCO is looking to pursue SC to SC trades. And that's what Resource Adequacy means for Anza Electric.

The City of Azusa, to their credit, was the very first to provide us with a -- I'll just leave it here -- was the very first to provide us with resource plan data on December 4. For the year-ahead filing Azusa procured 15 megawatts from Indigo 1, 2 and 3, just for RA purposes. And Azusa cannot call on Indigo for energy but the owner must now make that capacity available to the ISO. Several other POUs in SP15 bought shares of Indigo through SCPPA just to comply with RA tariff provisions.

Many small POUs in Southern California kindly provided copies of their RA filings prepared for the ISO. From these filings it has been possible to see how different POUs have built a portfolio that is mixed and balanced in many respects. Local and import, owned and contractual. I do need to go back here. Baseload and peaking, LD and renewable contracts. A mix of and balance of short-term and long-term, must-take and call options, year-round and seasonal.

Decades ago many Southern California POUs purchased single digit megawatt shares in large out-of-state generating stations such as Hoover, Palo Verde and San Juan. More recently many of these same POUs have purchased shares in renewable projects packaged and financed with the assistance of SCPPA such as Ormat geothermal and Wildflower. I don't have time to go into details except to acknowledge we have received excellent filings for the first time from many small LSEs including the City of Banning, the City of Cerritos, Colton, Corona, Rancho CUcamonga and Vernon. We still expect to receive a filing in the near future from the City of Industry and Moreno Valley.

I'd like to say a few words about the city of Vernon, appreciatively, just to be different. Vernon had a peak load of 197 megawatts last year.

Based on a projected three percent annual growth in peak demand Vernon could join the 200 megawatt club this year.

Like most LSE's in the ISO Vernon's RA statements defined qualifying capacity in terms of local conditions. Here is one example: "Generating units and system units, excluding Vernon diesel generating, shall count as qualifying capacity. The amount of qualifying capacity will be based on projected dependable gross output on a day when the ambient air temperature is 90 degrees Fahrenheit." And Vernon provided both a non-coincident peak load forecast and another table showing Vernon's share o f the forecast system peak in the California ISO control area. Vernon uses a 15 percent planning reserve margin, at least for the ISO filings, that is based on Vernon's contributions to the forecast system peak.

There is yet another variation on how publicly owned LSEs can acceptably and appropriately define their responsibilities for meeting peak loads. The Northern California Power Agency, NCPA, operates a power pool for ten of its members in the California ISO control area: Palo

Alto, Alameda and the Port of Oakland; Ukiah and Healdsburg; Biggs and Gridley; Plumas Sierra, Lodi and Lompoc.

NCPA operates and schedules for the pool members reserves and loads in an aggregated portfolio. On behalf of the pool members NCPA secures capacity adequate to meet the coincident peak demand of the pool plus 15 percent for capacity reserves. Since NCPA power pool members are in a metered subsystem, by agreement, available capacity resources must be available to the ISO during an emergency.

Roseville and Silicon valley are no longer members in the NCPA power pool. However, Roseville and Silicon Valley retain individual rights to schedule and dispatch Collierville hydro, a 207 megawatt plant on the Stanislaus River, which they share with NCPA. And these three entities do commit that resource independently, which makes for an accounting challenge to keep track of water storage and dispatch.

After our forms and instructions for resource plans were adopted Antonio Alvarez of PG&E suggested it would be appropriate to ask not for the LSE monthly non-coincident peak resource loads, but instead to ask for the LSE's peak resource needs at the time of system coincident peak load.

Antonio Alvarez gently pointed out that PG&E had successfully made this case for establishing obligations of LSEs in the year-ahead and month-ahead filings now required by the ISO tariff. I thought at the time this discount to the obligation, which might be two or three percent, should not be factored into long-term procurement plans, especially when the aim is to acquire just 103 percent procurement of firm load in the preceding fall, and 115 percent procurement by the preceding month. But here's a filing that makes an even stronger case that we should use the coincident system peak as a basis for any RA obligations imposed on individual LSEs.

And here I need to minimize this and call up a particular filing. The California Department of Water Resources provided an absolutely fascinating set of forms and statements. DWR operates the State Water Project, and this project uses more energy for pumping than it generates at like Oroville and San Luis.

Jon Seehafer provided this illuminating analysis: In describing SWP's load and resource balance I have provided two alternative views. One is the actual State Water Project peak demand, which by design occurs during the off-peak hours. This actual peak number is the number you requested so I provided it, but the number that is properly of interest is the one that corresponds to the system peaks of all the LSE's who are serving retail electric customers since this determines the constraining boundary that has to be planned against.

That is the actual. And by doing a little toggle we can change all the loads here, as you see. Just a remarkable convention for peak LSE and system peak monthly load forecast.
Mr. Seehafer also wrote: "A better number would have been the average State Water Project load during superpeak hours, say between 1400 and 1900, which I could provide."

"The SWP differs from most LSEs in that it is not obligated to serve its entire load at all times. While a portion of this load is firm, the majority of SWP load in any given hour could be deferred, freeing energy for others to use in the immediate period. Demand response is not exactly a free service for the State Water Project because of the increased wear on the units, but SWP's customers are not otherwise disadvantaged, assuming the pumping is made up in a reasonable time."

And Mr. Seehafer offered this counter-intuitive insight on forecasting demand for the State Water Project. "DWR's worse case scenario in terms of energy demand is the normal water year because that would mean both that water demand existed and water was available for pumping. In the alternative cases, either the water year is below normal, reducing the available water supply, or the water year is above normal, reducing water demand. Either alternative would effectively reduce the energy demand for pumping."

The Western Area Power Administration is the local regulatory authority for the loads that it serves in the Cal-ISO control area. Western maintains the ISO tariff regarding RA does not apply to Western because Western does not serve retail load. Instead Western schedules for specific customers and specific loads, starting with project use, then first preference customers like Trinity PUD, then base resource customers like Biggs and Beale and BART, along with Indian rancherias and UC campuses. After that Western serves 19 full load service customers like Lassen and Pittsburg. And after that Western serves DOE laboratories like Lawrence and Stanford, and those loads are sometimes met in part by third-party contracts.

In a plan filed with the ISO in September, Western committed to make a year-ahead showing that it has a minimum of 90 percent of the capacity needed, required, to meet its forecasted monthly coincident peak load in the CAISO control area, as determined by Western, plus its planning reserve margin. And that planning reserve capacity will be ten percent for the months of June through September and five percent for the months October through May. And for its month-ahead showing Western will demonstrate that it is prepared to meet 100 of its forecasted monthly coincident peak load.

Western's LRA defines how its vast hydroelectric capacity counts for its year-ahead voluntary filing. Western designates its hydro facilities in the SMUD control area as a system resource, with 100 percent of its forecast capacity as qualifying capacity. Using Western's 50 percent, that's a median forecast, rolling 12 month forecast for the appropriate month.

And for New Melones, Western and the ISO have agreed to pseudo-tie the generation from New Melones into the SMUD control area electronically and operationally so that it can all be scheduled as firm energy, an imported resource to the California ISO control area that is backed by reserves in the originating control area.

Burbank Water and Powers uses the minimum planning reserve and reliability criteria that was approved years ago by the Western Systems Coordinating Council. For planning Burbank uses a performance criterion of meeting all loads in a year 90 percent of the time. That translates to a one chance in ten that loads in any given year will exceed available resources, plus reserves that are equal, at least equal to Burbank's greatest risk. Burbank's largest risk is its share of Magnolia. And Burbank's load responsibility within the LADWP control area is to provide for our own load.

Glendale Water and Power has a planning

reserve requirement also based on its largest contingency, which is the loss of Grayson Power Plant's Unit 8 B and C, equal to 74 megawatts. Thus, Glendale maintains electric resources equal to its forecasted peak load plus 74 megawatts. Based on median demand forecasts this translates to a planning reserve margin of about 23 percent. Glendale's all-time peak demand of 336 megawatts came during the heat storm last July.

The Los Angeles Department of Water and Power determines what the key reserve margin is using the WECC rule regarding the loss of the single largest contingency. For LADWP the loss of Haynes Units 8, 9 and 10, a combined gen-set, is the most severe single contingency in most cases.

The second most severe single contingency, again in most cases, is the loss of one intermountain power project unit. These contingencies define capacity amounts that are needed for contingency reserves and replacement reserves, such that the system reserve requirement at peak load conditions is 1,106 megawatts.

For utility-run control areas, LADWP does something else that might be defined someday as best utility practice. Quote: "Under its interconnection agreements with Burbank and Glendale, LADWP verifies with each POU in its control area the resources providing the necessary reserve requirement in regards to each POUs respective, most single severe contingency. Verification includes the task of establishing and monitoring Burbank's and Glendale's share of this requirement, based on their coincident, most severe single contingency."

Statements by SMUD on their RA obligations and standards were brief and to the point. Gary Lawson will be speaking for SMUD later this morning, I hope. I would like to highlight one paragraph in their filing, unique among all the LSE filings, that attests to their certified expertise in several well-defined planning categories.

"SMUD follows the NERC functional model for assigning responsibilities to comply with resource planning requirements. From a planning perspective SMUD has registered with NERC as a transmission provider, a transmission owner, a resource planner and a planning authority for the SMUD utility footprint. Other participants in the SMUD control area have registered accordingly for their footprint. SMUD control area operational responsibilities are limited to such functions as those prescribed for a balancing authority and transmission operator." Unquote. Those categories of expertise might be suitable for future surveys by the Energy Commission and these areas might also be referenced in the formal RA policies of individual LSEs.

Modesto Irrigation District does not have a formal, Board-approved RA policy at this time. MID staff develops a demand and energy forecast annually and prepares a resource plan twice each year. Interestingly, and unique to Modesto, the MID system peak demand forecast is based on a 1-in-3 peak temperature buildup probability of 106 degrees Fahrenheit or greater. And there's this: MID operates as a member of the Western sub-control area within SMUD's control area. MID is obligated to self-provide or purchase spinning and non-spinning reserves for its share of the Western sub-control area. MID also pays a monthly regulation fee to Western for the right to operate within a nine megawatt regulating band.

Immediately south of Modesto the newest

control area in California is operated by Turlock Irrigation District for the benefit of TID and Merced Irrigation District. Interestingly, this year Turlock provides nearly all the capacity and energy that Merced needs for its loads, other than a modest supply from Western that comes in through TID. And that's why the planning reserve margin changes at the end of 2007. Turlock, it's the same number but they're not covering Merced's load by contract as a firm obligation after 2007.

Turlock is committed to establishing a demand forecast by June 1 for summer months in the following year. And also by June 1 TID is committed to acquiring 105 percent of dependable capacity to serve peak loads in the summer months of the following year, May through September. This self-imposed deadline for procurement targets is months earlier than the standard imposed by the ISO tariff. The month-ahead procurement standard, however, is practically identical. For example, 115 percent by April 30 for the median forecast peak load in June.

TID has one statement of delegated authority that staff in other LSEs might envy. Quote: "The Board of Directors of TID hereby authorizes and directs staff as assigned by the General Manager to take such actions as are reasonably required to prepare its Demand Forecast and Supply Plan and to comply with its Supply Plan." That's empowerment for good planning and timely actions.

In a few other areas TID is more discriminating than LSEs in the ISO control area about what counts as dependable capacity. For example, hydro capacity from New Don Pedro is, quote, "based on current reservoir levels and snowpack, and a 1-in-5 dry year forecast precipitation." Unquote. For their run-of-canal power plants capacity is based on actual or forecast flows and canal head. That's the kind of integrated water and power forecasting one might hope for from a load-serving locally-based irrigation district.

In the interest of time we don't have much to say today about the RA policies of Redding, Roseville or Imperial Irrigation District except that Redding, for example, has historically utilized a 15 percent deterministic planning reserve margin and REU will meet the requirements for resource adequacy as established by the WECC.

that policy seems most appropriate since their resource planner, Nick Zettel, is serving on the WECC loads and resources subcommittee addressing this subject.

In our survey we found there are at least five other organizations that could serve load but that are not serving load currently, including the City of Chula Vista that's organized and authorized to be a community choice aggregator but is not doing so. The City of Santa Maria that made efforts to do so but has abandoned that.

Monterey County Water Agency, which by statute is allowed to build hydro facilities in the Salinas Valley, which they've done, to generate some hydro energy at Nascimiento. They could sell it to other end users but we've discouraged them from doing so and becoming an LSE actually. They are continuing to market that as renewable energy to those that have a need for it in their RPS programs. So we call those --

ASSOCIATE MEMBER GEESMAN: Did you say that we had discouraged them from doing so?

MR. WOODWARD: This was a casual aside from me to the Monterey County Water Resources Agency planner in discussion saying -- not a discouragement just that the reporting obligations for an LSE might be more than they want to take on as a flood control and water management agency. That was a bit casual, thank you.

We consider Chula Vista, Santa Maria and Monterey County Water Agency as a kind of no load LSE for now.

ASSOCIATE MEMBER GEESMAN: Yes. I hope I don't need to remind you that this is an area that's pretty fraught with policy judgements that the law generally leaves to elected officials or appointees. And that in an area that is potentially controversy prone it would probably be prudent for staff to avoid venturing too far with personal opinion.

MR. WOODWARD: Okay, thank you.

Again, I would like to emphasize that our communications with publicly owned LSEs have been respectful, rewarding and forthright. We appreciate the good work of staff at these LSEs who are helping us address our new AB 380 responsibilities.

And I would add that the activities that are hallmarks of a well-rounded, balanced and complete RA protocols address the LSE responsibilities for load forecasting, resource planning, procurement, scheduling, coordination with a control area or real-time operations. There are many California publicly owned LSEs forward-looking that are doing that job.

Thank you. Are there questions on the phone, Mr. Vidaver? Comments?

Are there questions, comments from the dais?

I've gone long so with apologies for that I'd now like to call back up to the podium Mike Jaske who will, who will help us towards an understanding of prudent planning possibilities and challenges for reporting progress and developing statewide policies.

DR. JASKE: In the light of time I am just going to mention three specific issues that I think would be worth our attention and ultimately the Commission will have to deal with in terms of how it chooses to report to the Legislature. The first is -- All three of these are things that are the reality of the world and that go beyond any of the literal language of AB 380 and so there is judgment involved in how to pursue them.

The first is the whole issue of local

capacity requirements. For those entities that are within the ISO control area this is not yet an obligation upon them but which is anticipated in the MRTU tariff and it will evolving over the course of the next six months, nine months as the ISO works to file clarification tariff language.

A complication in this whole area is how to quantify and develop those local area requirements. In the manner that the ISO is doing right now it necessarily involves the way in which the transmission system is analyzed and the contingencies that are common across what otherwise seem to be control area divide.

So there are transmission assessments being done with what is the SMUD, WAPA and Turlock control areas sort of embedded within the PG&E transmission system. So far transmission planning and analyses have not successfully disentangled all that and perhaps that reflects the reality of the way the transmission system actually operates.

ASSOCIATE MEMBER GEESMAN: What type of forum is being used to flesh that out?

DR. JASKE: The ISO established a technical advisory group for local capacity requirements last fall. It met a number of times over the course of the fall of 2006 in preparation for the ISO's analysis of 2008 requirements. I guess I would say that forum wasn't completely successful in resolving various technical issues and so there are, I believe there are plans to convene, you know, a technical advisory group once again as the ISO gears up for its analysis of 2009 local capacity requirements.

ASSOCIATE MEMBER GEESMAN: And is that something that is focused on stakeholders within the ISO control area?

DR. JASKE: Predominately, would be my understanding. There are some issues. And we have a representative of the ISO here today who perhaps can help clarify this. There are some challenges that even the large PTOs have with being able to replicate the analyses that the ISO staff has done.

ASSOCIATE MEMBER GEESMAN: Yes, I've seen reports of that in the press that the numbers appear to have jumped around from year to year.

DR. JASKE: Well they have, which may well be a proper analysis. But there are concerns that have been raised by the PTOs in their filings to the PUC about LCR that, you know, create concern about the ability to duplicate the ISO's analysis. And it may not be something that can be resolved in the time frame of the remainder of that process, which is currently scheduled to have a decision issued this month and to be adopted by the PUC next month so as to set up the local capacity requirements for next year. It may have to be, in effect, moved forward to the analysis for the subsequent year.

ASSOCIATE MEMBER GEESMAN: If the PTOs are having a difficult time replicating the numbers does it go without saying nobody else can either?

DR. JASKE: I'm not sure anyone else has even tried. It's a large job.

ASSOCIATE MEMBER GEESMAN: So that doesn't sound like a particularly transparent analytical process.

DR. JASKE: There are concerns that it's less transparent than it should be.

ASSOCIATE MEMBER GEESMAN: So how would, how would we or anybody else go about applying this non-transparent, non-replicable, non-representative forum result to participants outside the ISO control area? That might be a loaded question but it just appears to me that we may be pursuing something that is not ready for prime time.

DR. JASKE: Well there is no direct obligation placed on entities outside the ISO control area through that analysis. If I understand the way it operates presently for 2007, the first year of requirements, and the plan for 2008, the LCR analysis in effect will lead to requirements for given pieces of the transmission system that we call load pockets that have both PUC jurisdictional and POU loads within them. There will some sort of partitioning between those two on the basis of load shares.

And if and when the ISO moves its resource adequacy tariff to implement the sentiments previously put forward in the overall MRTU tariff there will be some process to create obligations on the POUs that don't now exist in calendar year 2007.

The second area that I think is an issue at some level is that of POU control area operators. Near the end of Jim's presentation he quoted some sentiments from SMUD. And if you think back to the presentation that Adam Pan made earlier this morning, of the entities in the SMUD control area SMUD itself, MID and Roseville are all short in the near-term. So when we're in the position of rendering a judgment about whether those areas were adequate from a capacity reserve perspective one might well say that they are short. Redding is the only one of the four that is long in the short run.

And it is unclear to me that SMUD's disclaiming of planning responsibilities for those other entities is in fact compatible in which the way SMUD is reporting information up to WECC. So we need to do some more examination of that issue. And as I mentioned earlier this morning this whole notion of POU control areas and what responsibilities they have separate from the POUs as a utility needs some clarification.

And thirdly, going even further down that path, I think one could also question whether the WAPA Western perspective that it is not a load-serving entity, that it is in fact accurate. WAPA has a plethora of customers. Clearly many are wholesale transactions to other utilities but this large set of federal and other entities that have federal power entitlements look a lot like end-users to me.

So I believe the way the Energy Commission's own regulations define a load serving entity WAPA would be an LSE by that term. WAPA is not specifically defined as part of the AB 380 definition of a POU yet it's a significant amount of load and the Energy Commission may well want to consider how it reports about WAPA Western in our report to the Legislature.

So those are the three areas that I think are sort of challenges for things that don't sort of neatly fit into how one plainly reads AB 380 that eventually you'll have to deal with in our IEPR section or appendix reporting to the Legislature. Thank you.

MR. VIDAVER: We have a request on the phone from James Farrar of Turlock Irrigation District to speak. Mr. Farrar, are you there?

MR. FARRAR: I'm here but I think they already covered the subject adequately, thank you.

MR. VIDAVER: Thank you.

MR. WOODWARD: Thank you, Mr. Farrar. For others who wish to call in, again the number, the correct number is 800-857-6618. Again, 800-857-6618. We have one operator standing by.

Are there any other comments here in the room or from the dais?

If not I believe we have one speaker on the line on the program. We'll skip ahead a bit. Mr. Brian Koch from the Los Angeles Department of Water and Power. If you're there, Brian, the microphone is yours.

MR. KOCH: Yes, I'm here.

I think most of the presentation has already covered -- Several of the speakers talked about our plans and future. As noted by Adam's charts, which looked very consistent with the way we show them, we feel we have our internal adequacy, resource adequacy covered as well as what we do for Burbank and Glendale.

So I don't know if there is any specific out of those questions you wanted me to address or if there was something special, a special issue you wanted.

MR. WOODWARD: This would be your opportunity to add to what we've put into the record or correct it or amplify and improve the understanding in this area where LADWP does indeed have multiple roles. That you serve as the nation's largest publicly owned LSE and operator of a control area.

MR. KOCH: I guess the only thing to add is that, you know, we have renewable energy goals that are at least 20 percent as of this moment and may be increasing in the near future here. And that will change our resource mix per se but we are currently resource adequate.

And I think we adhere to the WECC standards. We use the contingency process that was described for our largest contingencies, which bring our number above the 15 percent requirements that were mentioned for most of the other POUs on that list.

So I think we've described adequately, and your charts have described adequately our process. We work closely in our control area process on a daily basis with the Glendale and Burbank folks on a daily and the long-term basis to make sure that their resource adequacy needs are reflected in what we do and how we work with them. And as far as I know you've got, what's in the record is correct as of this moment.

MR. WOODWARD: Thank you, Brian.

Do we have Gary Lawson here with us? It's helpful to have representatives of those LSEs that actually do sign contracts, serve load, manage control areas, provide transmission and the like to speak more directly from your concerns about knowledge of resource adequacy.

MR. LAWSON: Thank you. We have some prepared responses to the questions that were attached to the agenda. I don't know that I'll cover all those because it seems like a lot of this has been discussed.

I would like to reiterate that SMUD does use guidelines for meeting resource adequacy requirements and we do follow the criteria for counting loads and resources as laid out in your guidelines. And in addition we have adopted time lines comparable to what the CPUC has for the investor owned utilities in terms of year-ahead and month-ahead procurement.

Question four touches on how the resource adequacy margin relates to reliability standard. We have a few comments on that. Our Board has adopted a set of reliability goals and objectives. Primarily those lay out service interruption numbers.

As a planning standard we do meet WECC and NERC reliability criteria and how they describe our serving of load. We do plan our system capability to serve one- and ten-year loads while meeting the WECC and NERC criteria. And we do operate to the WECC and NERC criteria on a real-time and day-ahead basis.

Resource adequacy we view as dealing specifically with resource procurement targets. And while resource adequacy and procurement does have an impact on reliability ultimately reliability is how well you serve customers and do so meeting WECC and NERC criteria.

Our role, it was discussed our role as a control area operator. Again, we do, we do take that role based on how NERC has defined its business model and the roles within its business model. We do not perform the function of a planning authority for WAPA or its member load serving entities.

Our system operations and reliability group supervises control area reliability on a daily basis as a balancing authority and we cooperate with the other control area entities to assure that we are operating to NERC and WECC criteria.

Regarding the need for potential changes to resource adequacy oversight of POUs. Under a certain circumstances there could be benefit to more standardized criteria. However, our feeling is the key is not to be so prescriptive as to prevent LSE flexibility. And we heard a lot of diversity of the various LSEs today.

To put the issue in perspective, much of the resource adequacy problem has been precipitated by reliance on organized markets, which so far have failed to a certain extent to provide long-term capacity. The state has had to step in to reestablish an obligation to serve on the investor owned utilities. For POUs such as SMUD, we never lost the obligation to serve and we have always taken resource adequacy and the allocation to serve very seriously.

Regarding a possible WECC or NERC role in defining resource adequacy. I think it was mentioned earlier that WECC is pretty much going to lay out an assessment guideline.

And we're participating on the NERC level as well and we feel that NERC is headed in that direction. We don't expect them to focus so much on the timing and how you go about resource procurement, which is really what I think we're talking about here. They're more focused on reliably serving of load. They recognize that it is up to state and local regulatory bodies to determine when and how resources are procured.

And I think that's probably all I need to comment on.

ASSOCIATE MEMBER GEESMAN: Dr. Jaske characterized SMUD as being short from a resource adequacy perspective in the short-term. You obviously feel differently. I wonder if you would elaborate on what you think the difference in your two assessments are and comment on how material and important those differences may be.

MR. LAWSON: Well we do rely on different market products to develop a balanced portfolio. We have internal risk management protocols that we do to mitigate and balance financial risk and we follow those in our resource procurement as well.

We have an obligation to serve load and we will serve load. We feel that the market for those products is available. And it is a small percentage of our portfolio and we feel it is an appropriate percentage.

ASSOCIATE MEMBER GEESMAN: How do you

deal with the argument that implicitly you are shifting resource adequacy costs into a larger base of customers beyond just SMUD's customers?

MR. LAWSON: I'm not sure I have an answer for that today.

ASSOCIATE MEMBER GEESMAN: The argument I think from the ISO control area is by having resource adequacy criteria of your own, which they view as inferior to their's, you are in fact shifting costs from your customers to ISO customers as a result.

MR. LAWSON: We procure our resources out of state as well as in state, as well does the ISO.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. WOODWARD: Thank you, Gary. And I recall that when SMUD began its control area operations it had to do with a combination of reliability and cost and financing concerns.

Next I'd like to call on Mr. Joe Lawlor of PG&E for another comment and perspective from an LSE operating within the ISO.

MR. LAWLOR: Thank you, Jim. Phil is actually on the agenda before me. Do you want me to go first?

MR. WOODWARD: Please do.

MR. LAWLOR: Thank you for allowing me to speak today. I'm Joe Lawlor, Pacific Gas & Electric Company.

As I stated earlier, I've been involved in the CPUC's resource adequacy process for a couple of years now. I appreciate all the work that you're doing here to review the other POUs resource adequacy metrics, let me use that term.

I think for it is worth stressing the unitary nature of grid reliability. In my mind I was going to follow Phil so I didn't want to say too much on that but just the idea that reliability is assured by all of us. We need to, both the jurisdictionals and the non-jurisdictionals, know that we're adequate or there's a certain amount of leaning and maybe reliability isn't there.

Reliability requires planning and looking at that planning forum. Not just carrying reserves or looking forward to have an operating reserve level. Another important piece of resource adequacy that we are trying to address is how to fairly allocate the costs of that planning reliability.

The CEC review's here I think like I said is a fantastic way of trying to say, how does everybody view resource adequacy. And I think we're seeing a lot of information here that deserves a further look.

One thing that jumps out at me that I noted earlier was the amount of contracts. And to the extent that there's LD contracts in that mix I wonder if our difference resource adequacy paradigms aren't conflicting with each other. The PUC's paradigm says look at solid capacity in the ground. I can buy a capacity product. That same plant could then sell an energy product to somebody else and it looks like somebody not under the same accounting rules might be counting that under their paradigm. And in that way those megawatts are essentially double counted.

Another portion of this is, you know, who carries the fair cost of planning for reliability. I know I've seen something from WAPA today, or heard from WAPA today, that they're looking at a winter planning reserve margin of five percent. The PUC jurisdictionals are carrying a 15 to 17 percent reserve margin.

On a planning basis, if that is supposed to be the forward obligation that people think of that then later might be reduced by forced outages, and if there is an operating reserve of five to seven percent it doesn't seem like the WAPA reserve is carrying a fair share and we'd be leaning on jurisdictionals.

I appreciate all the questions that were put forward today and PG&E will be prepared to respond to those in writing at our comment time. Thank you all.

ASSOCIATE MEMBER GEESMAN: Joe, I wonder if you would address the question of the inherent diversity or pluralism that current law imposes in terms of resource adequacy criteria. I catch the gist of your comments and have followed your company's position on this subject for a while.

It would seem to me that you would prefer greater uniformity if not a one size fits all policy but we don't have that. We don't have that under WECC, we don't have that with NERC, we certainly don't have it in state law. Could you give us your view as to what we're supposed to do in the absence of that single, common standard.

MR. LAWLOR: I think you've caught my comments accurately. That a common minimum standard would be very beneficial to judge all these and to make sure that the requirements are fair. Since we don't have that paradigm set up how do we get there? Or how do we get to a level that we think of is a fair allocation of responsible planning and ensures reliability?

I think the report that you are doing here is a first step toward that. Pointing out where these differences will exist. I don't think that that's been public. It may be public in different forums but I don't think it's been centralized enough for people to then have an informed discussion as to what's appropriate.

How to get to that minimum amount I'm not sure yet and that's an excellent question. The CAISO's tariffs I'd like to think as maybe a way to get there. I don't think that's purely applicable. Whether the Legislature will get you to some minimum standard I'm not sure that would apply to everyone either.

But those will be the kinds of things that I think this first step of putting the requirements together and seeing if it looks like a fair metric might be discussed later.

Thank you.

MR. WOODWARD: Thank you, Joe. And if you'd like to say something after Phil Pettingill has his comments we'll bring you back up.

I did note from many of the POU filings that they do indeed count as 100 percent firm capacity those Western schedule contract supplies, they're considered a firm resource. And Western made a strong case for why its hydro portfolio is fairly predictable in some ways.

I also recall that after the interagency agreement with PG&E expired at the end of 2004 that they had a lot of learning to do on what their dependable capacity was. Something they had relied on PG&E for for a great many years for balancing energy and demand in real-time.

MR. LAWLOR: Thanks, Jim. With the Western, and I have only briefly looked at it, I think it is interesting to point out there that how they count their hydro is actually different than the PUC paradigm of hydro. So when we get to looking at a total report that compares these things how do we point out those differences or how do we translate them to say, and here is a comparative analysis.

Our PUC adopted jurisdictional rules

rely on a dry hydro year and has defined that in a certain way. And I believe what I have seen on Western's is they are going to use an average hydro year. So things like that won't be necessarily directly comparable.

MR. WOODWARD: Yes, If I can recall that they do use that rolling 12 month average based on a median forecast. But they also made the case, I think well, that for summer capacity it is much more predictable looking at how reservoir fill is managed. And the real variations come in the spring months, much more variable. Much like PG&E's hydro system where May can be a huge swing between wet and dry years. So good point.

And another thing I meant to say, indeed in sharing what the filings have indicated this is meant to be a comparative and descriptive presentation. It is not meant to presume or assume that one standard is appropriate to use as a benchmark to judge the standard of another LSE or another control area.

And with that I'd like to call on Phil Pettingill with the California ISO.

MR. PETTINGILL: Well thank you. I do have a few comments just to share. I think it is in theme with -- first of all let me just back up and introduce myself. Phil Pettingill, I'm the manager of infrastructure policy at the ISO.

And I have had, I guess the pleasure of dealing with resource adequacy now for at least the last three years or more as we have tried to, tried to construct a process at the PUC as well as under the ISO tariff to try to create a paradigm where we understand how much capacity is out there. How much resources are actually committed to serving the loads within the ISO control area.

You asked a few questions about some of the processes we have and the inter-reaction with the PUC. And I'll just point out that it is really within the ISO control area.

And I think you asked a couple of questions about whether they could be applicable in other control areas and across the rest of the state. And I think we would argue that yes they could, partly because of the discussion that we have just been having. How to make sure that there is a comparable at least counting metrics in order to compare and contrast and then understand what are the public policy ramifications of those.

ASSOCIATE MEMBER GEESMAN: I guess Phil

where I get a little wary is when yes they could becomes yes they should.

MR. PETTINGILL: Yes.

ASSOCIATE MEMBER GEESMAN: You know, I hear a certain cadence over time that yes they could does morph into yes they should. And before we get there I'd like to just have a better and more clear understanding of what's the standard based on, why is it presumed to be superior and have all of the relevant interested parties had an opportunity to fully evaluate it.

MR. PETTINGILL: Yes.

ASSOCIATE MEMBER GEESMAN: And I know in the area of local capacity requirements there aren't too many people capable of conducting that review. And from a regulator's perspective that creates an inherent weakness.

MR. PETTINGILL: Sure.

ASSOCIATE MEMBER GEESMAN: You'd like to have something that can be replicated by multiple parties so that you can narrow your differences. If we're relying on one party to produce a black box result it doesn't enjoy the same level of confidence it would if it were something that multiple parties could replicate.

MR. PETTINGILL: Yes, I think that's fair and I think those are very fair observations. A couple of points I would share with you is that the local capacity analysis, this is the second year. We went through it the first time last year.

One of the lessons that we learned was there needed to be more transparency. And one of the things that we identified was to get a committee together of the technical experts. Who are the folks that do these kinds of analyses and to bring that group together. Certainly we weren't 100 percent effective in using that committee's results this year and we recognize that.

But I would just point out that because it was the second year out we already implemented that mechanism and our tariff is very clear. We continue to be committed to work in collaboration with the PUC and the other entities to try to create that transparency that you're talking about.

We did have a number of stakeholder meetings to try to describe. I think we had one, at least two of those meetings to try to describe how those analyses worked, what the results were, and explain how as you mentioned earlier, how some of the numbers had changed. And we wanted to make sure that the parties and the whole, at least the ISO control area, understood what was driving those changes.

In one instance there was a significant change in Southern California because it came out of our normal grid planning process. And so there are going to be changes because what's driving load pockets is the underlying transmission system. And as that transmission system changes or as loads grow that are modifying the results or the ability of the transmission system to serve then that may result in changes in the LCR requirements.

We see that as just informative. It makes it very clear then, how should the transmission system change. Or, how should parties make a choice that if not modifying the transmission system then capacity needs to be procured in order to maintain a consistent level of service from one year to the next.

ASSOCIATE MEMBER GEESMAN: Yeah, I don't think I disagree with any of that. But we were told yesterday, we spent some time in our hearings yesterday, that the DOE had singled out Southern California in its NITCI procedure as one of the two areas in the United States deserving federal intervention. And that's a fairly serious step in terms of a state surrendering land use sovereignty over important regulatory decisions.

It's a step that this Commission has anticipated in its reports for several years now and I think it's a criticism of all of us for not having done a better job in planning and building a transmission system up to the needs of Southern California.

But my concern about a lot of these resource adequacy criteria and planning efforts is that when they're extended beyond the short term, at the 12 month horizon that we have tended to focus on in state policy, they could be diversionary and take our attention away from necessary infrastructure investment.

And I don't think that particular dilemma has really been addressed in some of the proposals looking for multi-year resource adequacy or more commonality in resource adequacy criteria. My apprehension is that they pose an enormous risk of diverting our attention from things like long-term procurement or proper transmission planning or more efficient transmission permitting.

MR. PETTINGILL: Yes. I think those are fair comments. And talking about RA in general I would just second those.

I think some of the key objectives that certainly my organization has focused on is trying to make sure that there is at last the efficient capacity for reliable operations in the daily and short-term environment that we have. But the challenge is how to determine that. How to measure it. How to know that what is being done in the longer term horizon results in sufficiency in the operational time frame.

And certainly one of the difficulties there is to create the incentives so that parties have, as you mention, the flexibility to go about doing things in their own business model but to ensure that when we get to that operational time frame that no parties are necessarily or inappropriately, and I think that's a policy decision, leaning on other parties for what those folks have already done.

And I think that's the challenge. And

when we see some of the breadth of interpretation of RA as you saw today and how folks would intend to provide sufficient resources, then the question becomes, well how much and to what extent is one party necessarily relying on the procurement of another party?

And so in my mind I would just point out that there's a few key elements. And I think we saw them already come out today and this has been my experience over the last few years. That we first need to understand how we're going to do a load forecast because that's where all of this usually begins.

What is the need to serve that load? And our tariff now explicitly adopts the CEC in producing that load forecast so there is a consistency that's looking at folks' contribution to the peak load on the ISO control area. In doing that we think we can make sure that we're looking to you to help provide us that basis for the RA and where we begin.

Included in that should be energy efficiency. And we adopt that and accept that and that should be incorporated because energy efficiency programs are clearly going to reduce that load that's expected and necessary to be served.

But then we look at the other side of that, what I like to call the ledger sheet, and say, now what are the resources? And resources can cover the gamut as we have already talked this morning. Certainly they can be the traditional thermal resources, whether they be short-start, long-start, baseload resources or hydro facilities as well.

But included in that should be the dispatchable demand response. We should talk about how demand can participate in RA programs because it can be extremely cost effective and very beneficial to use in operating the system, as all of you know.

But once we start with those fundamentals then we have to move on to some of the more difficult elements and we talk about locational. Where are these resources at? Are these resources in fact deliverable to California load? We heard that some folks rely on resources from outside California. Let's be honest, California is a net importer. We all rely on resources outside. But the question is, do we have enough transmission to bring it in.

And you have seen us interact with our FERC commission in regards to establishing import allocations. So transmission and deliverability becomes a major portion in trying to make sure that the program works.

And then the last couple elements that generally I focus on is now how are the resources made available to the ISO. Certainly the benefits of having those resources in our markets or in some way made available so that we can pool them and use them in the most efficient manner.

But some parties do not want to make their resources available to us and as a result we have developed two tariff mechanisms under the MRTU design in order to have two very different RA programs function with the ISO and our operational requirements.

And so finally then the last step is, what do we do when we do find ourselves short? What's the public policy? What is the role that you would like for the ISO? And we have worked this out in substantial detail with the PUC.

But in regards to the long-term procurement when folks are short in the month ahead, the year ahead or in a multi-year RA program what's the expectation to try to backstop and fill that gap? And then on the short-term horizon, on the daily operations or under emergency conditions what is the expectation to fill that gap?

And those questions can be extremely challenging. But the ISO certainly sees a role and we'd like to fulfill that role in helping you formulate that across the whole, the whole system. I think we've worked out an effective role, at least within our control area. And that may be a place to look for other places as well.

But finally I think again I'd just summarize by saying the emphasis is to first now understand how we count, how we do a consistent load forecast, how we count the resources to be able to understand what does the system currently look like. And then that gives enough flexibility to consider how to go forward from here. And I'll stop with that.

We do continue to participate in your process here and I'm sure we'll file comments at the appropriate time just to provide some of these comments in more detail and specifics as necessary. Any other questions?

ASSOCIATE MEMBER GEESMAN: No, I appreciate your attendance and your participation throughout our process.

I guess I'd highlight two areas where I know you have heard this before but for the benefit of the others that are here today I think it ought to be reiterated. Two areas that are subject to quite a bit of contentiousness that we simply don't have a dog in that fight.

One is the presence of multiple control areas within California. But we certainly have benefited from, and I think California has benefited from the ISO's participation in our market. And we have tried to work together as closely as possible in the nine years that you have been in existence and I think that has been to the benefit of California in general. But we don't have a view institutionally at this point of whether there should be a single control area or whether there should be multiple control areas.

The second is the more historic point of public versus private power. We may have employees that jokingly discourage municipalities from serving load but we don't have a dog in that fight either.

And I think these discussions are productive ones to focus upon and intensify. But to the extent that either of those two issues come up I think you should expect policy neutrality on our part.

MR. PETTINGILL: Great, thank you.

MR. WOODWARD: Thank you, Phil. And for those who would like to see the wealth of information at the Cal-ISO filings we provided four links to other references on the second page of the workshop agenda, one of which is the Cal-ISO allocation of import capacity filings under MRTU. Another is an excellent overview by the PUC on their resource adequacy prepared earlier this March and Dr. Jaske's overview of RA last spring.

David, do we have any callers on the line? If someone does want to call in it's 800-857-6618.

Are there other speakers here in the room who would like to address the workshop?

Yes, I'm sorry. I have overlooked my responsibilities to keep track of the agenda at this point. It is my pleasure to introduce Mr. Tony Braun representing the California

Municipal Utilities Association.

MR. BRAUN: Madam Chair, thank you very much. I feel like I should be paying rent with all the time we've been here recently but it's been a pleasure.

I have scrapped all my prepared remarks so if I stumble around a little bit please, please don't hesitate but we will take on some of the more formal questions that were presented.

What I would like to do is perhaps share a little perspective here. I think the first thing we need to do when we look at municipal procurement is look at history and say, all right, what is the history of the public power community in California as far as meeting its obligation to serve?

And I think I don't need to expound upon this too much. Throughout the crisis, before, after and during, our procurement practices have been focused on that obligation to serve, even at times when perhaps there were shortages and which frankly can only be put one way, the system was leaning on us.

These things go in cycles and waves but our history of meeting the obligation to serve I think is reasonably clear with the empirical evidence that can be easily presented and has been presented by the charts. Let's not lose too much sight of that in those charts there that were fairly demonstrative of that, of those practices.

The second, Commissioner Geesman has pointed it out. We have a legal structure in place and it is what it is and it is reasonably clear. We do not have one utility in California, we do not have one regulator in California and so we are going to have diversity. And the diversity just within the municipal utility itself is fairly extensive as Mr. Woodward has pointed out.

He has shown a lot of the bookends but even within the traditional utilities themselves they have a lot of different practices which are borne out by historical agreements with Western or historical agreements with PG&E or Edison or the nature of their systems. And they're prudent practices. They have been borne out as prudent over time and they work. And with everything on our plate I wonder how much effort we should be putting into attempting to tweak them slightly.

The unity of the grid. That is something that came up recently. When I first started working in this business I was reviewing interconnection agreements that some of my clients had with PG&E. And this was a time right after Diablo Canyon was built. And they had provisions in them that said that you must carry a reserve requirement the same as our reserve requirement, which was at that time around 35 percent.

Is that the logical extension of the unity of the grid argument where whomever has the highest reserve margin is the one that everyone needs to go to in order to eliminate what is perceived as leaning? In that logic of course everyone would be leaning on LA. But I don't see LA going out and asking everyone else to raise their procurement standards.

So we have got diversity on the system. Everyone is operating consistent with prudent utility practices as a general rule. Maybe there's some counting rules, there's some things we need to tweak up to make everyone more comfortable and policy makers more comfortable that we are doing our best on procurement consistent with the reliability needs of the grid.

If we were going to have a place to go to I think my clients would look to the WECC. Now they move a little slower than some of us would like and perhaps some of the other entities in the room. But it is a place, I think, where a lot of industry participants are comfortable. We have already recognized that the WECC is one large market and that one procurement practice in one region, sub-region, affect others.

So that to us is a logical entity to look to if we're going to have unity. But it is going to take some ceding of control and not just by my clients but others as well. I don't know if we're ready for that but if we are going to suggest one entity that is where we would go.

So what are we down to talking about? We're talking about refining counting rules, we're talking about getting better information, we're talking about getting better transparency. Commissioner Geesman, I couldn't express better the municipal community's concerns about the local capacity requirements. We have expressed concerns about the transparency.

We have expressed concerns about the methodology. They are very difficult, they are time-consuming analyses. They get bogged down in regulatory proceedings that are moving on fast tracks and so they are not subject to adequate scrutiny. To my knowledge there has never been an evidentiary proceeding to examine these.

There's been hearings and workshops but let's face it, you can't do discovery and start ripping apart the methodologies that underlie the studies if you don't understand them. We would urge that type of procedure for the 2009 process and we would urge the Commission to look at this and see what there happens. Because I'm concerned that when we get to the 2009 process again we will say, well it's too late to take a fresh look at these things.

So what are we down to? We're down to deliverability. This is a major issue, Phil is correct on this. We, I think, made a lot of strides on import counting rules so that we don't over-count our imports capability into the system.

Load forecasting, we've made strides in that. We frankly don't have a whole lot of concern on that because it would make no sense for internally our load forecast to be wrong because that would ruin our risk management processes. So we have made a lot of strides on attempting to harmonize the load forecasting methodologies.

The pooling aspect. We have an MRTU order now. There's things we'd like to tweak about it that we should consider. We have a metered subsystem construct which has a limited exemption from that pooling but requires strict operational requirements of the metered subsystem operators to operate within a deviation band with significant penalties if they don't. So I think we have made significant progress on that.

So I think we are here basically refining our analysis. I don't think that we've got a big -- This is an issue which we applaud the PUC for all the effort that has been taken on. And we'd like to make sure that -- we think the examination under 380 is pretty limited. We would urge the Commission to stick to that in the report, in the IEPR, and allow the progress that is being made at the PUC and at the ISO and within the municipal community to continue.

Thank you. And I'd be happy to take any questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. WOODWARD: If there are speakers here in the room who would like to address the workshop please come forward and introduce yourself again. Partly because we have a record of this workshop and especially for those that are listening in on the web.

MR. ZETTEL: I'm Nick Zettel from the City of Redding, again. I'd like to thank Tony for all his comments and I'd like to echo those as well.

One other issue I just want to bring up real quick is Dr. Jaske and I are on the, along with Grace Anderson on your staff who is a wonderful contributor, are on the loads and resources subcommittee at the WECC, who has done a lot of work in developing resource adequacy kind of guidelines for what makes up 15 percent.

We hear 15 to 17 percent in the ISO but what is it made up of? How did it get there? The committee at WECC has done a lot of work and AB 380 clearly states the responsibility of the POUs and where they have to look. And I want to encourage the Commissioners to have your staff continue working at WECC and possibly kick it up a notch as far as CEC cooperation with or working with WECC on the standard because I think that is the appropriate place.

There are many resource adequacy standards. There's the ISO, Salt River Project, Tucson EPS, Pacific Northwest, you know, Rocky Mountain. We're all in one big grid here and WECC is definitely the appropriate place. And that's where Redding will be looking to for guidelines. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. WOODWARD: Thank you, Nick.

MR. HAHN: Good morning. I think it's still morning. My name is Ernest Hahn and I am here today representing the Metropolitan Water District of Southern California.

I hesitated even to come up here but when I heard about a lot of the smaller utilities I said well, I think I need to speak up because we're a little bit larger on some of our loads than even some of the smaller utilities.

I appreciate this opportunity to provide you some brief information on how Metropolitan serves its wholesale pump loads on its Colorado River aqueduct. Metropolitan is the largest water, wholesale water supplier in Southern California providing supplemental water supplies for domestic and municipal uses to its 26 member agencies in Southern California. This supplemental water serves 18 million consumers within a six county region of Southern California, an area covering nearly 5200 square miles.

One of the major sources of water for Metropolitan is from the Colorado River. Such water is conveyed over 240 miles to our aqueduct. There are five pumping plants along the aqueduct, each equipped with nine pumps to lift the water over and through the mountains west of the Colorado River and through the Mojave Desert.

The terminus of our aqueduct is Lake Matthews located near Riverside, California. From there water is distributed by gravity throughout Southern California to treatment plants at our member agencies. I've referred to the aqueduct pump loads as wholesale to distinguish them from our other Metropolitan loads as served by retail load serving entities.

Metropolitan's retail loads, including our water treatment plants and office facilities are served by Southern California Edison and other publicly owned utilities. Metropolitan's wholesale loads consist of our pumping plants along the aqueduct that can be served by Metropolitan through our own resources and both power purchases or exchanges.

Metropolitan's aqueduct electric system is designed to meet maximum pumping loads of about 320 megawatts with eight to nine pumps operating at the five pumping plants. Such maximum loads cannot increase in the future because of conveyance capacity limitations.

To supply its aqueduct pump load Metropolitan has entered into long-term contracts for power from Hoover Dam and Parker Dam power plants. So specific resources. Metropolitan has long-term rights, up to nearly 310 megawatts from these two facilities alone. Additionally Metropolitan has the ability to interrupt up to 110 megawatts of pumping at two of its plants for a limited time without losing water or spilling water from the aqueduct.

Metropolitan's aqueduct pump loads are served through an integration and energy exchange contract with Edison that has been in place since 1987. Under this agreement Edison combines the aqueduct's pump loads and resources with its own retail loads and resources. Edison schedules

Metropolitan's Hoover and Parker resources to meet the combined loads. Edison also has the ability to interrupt up to 110 megawatts of pump loads at our Gene and intake aqueduct pumping plants.

In return Edison serves the aqueduct pumping loads including ancillary services, replacement capacity and provides additional energy to Metropolitan. Therefore for resource adequacy purposes the requirements for Metropolitan's aqueduct pump loads are satisfied by Edison. Edison reports on the aggregated loads and resources, including Metropolitan's aqueduct system, in its RA submittals.

Thank you. If you have any questions I'm available.

MR. WOODWARD: Thank you very much. Appreciate how Metropolitan Water District has integrated its loads and resources with Southern California Edison.

Do we have any other speakers here in the audience?

Are there some comments from the dais?

PRESIDING MEMBER PFANNENSTIEL: No. I would just like to thank everybody for participating, for being here, for sharing information and helping us understand. Thank you.

MR. WOODWARD: Thank you, Commissioner Pfannenstiel. In closing I'd like to thank everyone again for your participation, for speakers and presenters, for those who shared information with us.

An overall impression I had in talking with resource planners is that they are immensely proud of their contributions to reliability for their rate payers and for those with whom they are connected through control areas in the grid. And there was a great deal of pride in having met peak load. Many of them hit all-time peaks last summer well beyond their demand forecast and some were glad to join a higher rating in that respect.

But they are looking forward for the long run and doing their best to work within a variety of constraints and constructs.

Again, thank you. For those who would like to provide written comments we request that they be provided to us by May 31. Thank you and that concludes our workshop.

(Whereupon, at 11:48 a.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 24th day of May, 2007.